The Welfare Impacts of Restructuring and Environmental Regulatory Reform in the Electric Power Sector

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Abstract:

The American electric power industry is undergoing dramatic changes in the way it is structured and regulated. As of September of 1998, state utility regulators, state legislatures or both in 18 states had made the decision to implement retail competition within 5 years or less. Competition in electricity markets and associated new opportunities for expanded inter-regional electricity trading could result in substantial changes in the mix of generation technologies employed to produce electricity, in the efficiency of power plant operations, and in the price and quantity of electricity traded in the marketplace.

This study evaluates potential retail competition and proposed new regulations to reduce NO_X emissions. We present estimates of changes in economic welfare resulting from projected changes for the year 2003 in electricity consumption and generation and associated environmental effects. We find that retail restructuring would produce customer and producer surplus benefits that substantially outweigh health damages from the slight increases in NO_X emissions. On the other hand, NO_X emission reductions enforced under an average cost pricing scenario (traditional cost of service regulation absent retail competition) would lead to customer and producer surplus losses that are only slightly less than their environmental benefits.

The NO_X emission reductions are less costly in terms of foregone customer and producer surplus when initiated in a restructured electricity industry. In this institutional setting, the additional effect of policies enforcing NO_X reductions is positive and substantial. Hence, we find retail restructuring has potentially important positive environmental benefits because it improves the affordability of NO_X emission reductions. Finally, we find that allowing NO_X trading, as opposed to uniform performance standards, can lead to a $200 million increase in consumer and producer surplus in electricity markets with virtually no change in aggregate health related benefits.

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I. Introduction

The American electric power industry is undergoing dramatic changes in the way it is structured and regulated. For much of its 100 year history, the industry has been organized largely as a collection of local integrated monopolies that generate, transmit, distribute and sell electricity at regulated prices to captive customers within a franchised service territory. Currently the industry is going through a period of unbundling of functions whereby the generation and retail sales markets are increasingly being opened up to competition. As of September of 1998, state utility regulators, state legislatures or both in 18 states had made the decision to implement retail competition within 5 years or less. Under retail competition, electricity consumers will be allowed to pick their electricity suppliers, but the delivery of that electricity to the customer's premises will continue to be handled by the regulated local distribution utility.

Allowing competition in electricity markets and associated new opportunities for expanded inter-regional electricity trading could result in substantial changes in the mix of generation technologies employed to produce electricity, in the efficiency of power plant operations, and in the price and quantity of electricity traded in the marketplace. These changes in turn could have potential implications for emissions, particularly of NO_X and CO2, for environmental quality and for economic welfare.[1] For example, if competition results in accelerated turnover of the generating capacity stock, then NO_X emissions could be expected to drop as newer gas combined cycle units have substantially lower NO_X emission rates than older units, particularly coal-fired units. On the other hand, if competition leads to more generation at older, higher-emitting coal-fired facilities, as some predict it will, then emissions of NO_X could increase as a result of restructuring. Electricity consumers will be better off as a result of expected reductions in electricity prices, but related increases in electricity demand could yield higher NO_X emissions and associated increases in environmental damages. The net effect of these changes in the industry is uncertain. Brennan (1998) illustrates how lower prices for polluting goods will lead to increased consumption of that good that can have ambiguous implications for social welfare.

At the same time that the industry is moving towards retail competition, it is also facing the prospect of new environmental regulations to restrict emissions of NOx. Some proposals would use the occasion of electricity restructuring to expand environmental regulations to ensure that NO_X emissions do not increase as a consequence of restructuring. Another proposal is embodied in the September 1998 EPA notice for revision of state implementation plans (the so-called "SIP call"). This proposal requires substantial reductions in total NO_X emissions from the generation sector, but also holds out the promise of a NO_X emissions trading program as a means for reducing the cost of achieving this emission reduction goal. Like industry restructuring, these new environmental regulations will have effects on electricity prices, consumer and producer welfare, pollutant emissions and environmental quality.

The combined effect of these changes is uncertain. The author of one recent study warns "It,s a double-whammy…(The NO_X regulations) coupled with deregulation will have an unprecedented impact on the industry."[2] This study concludes that older, less efficient coal-fired electric generating plants will find it difficult to compete with new NO_X regulations in a restructured industry (RDI, 1998). Meanwhile, another study that looked at reductions in NO_X emissions coupled with reductions in SO_2 in a restructured industry concluded that at least 94 percent of existing coal capacity would remain competitive with new gas-fired units (Biewald, et

[1] Total emissions of SO2 are capped under the requirements of Title IV of the 1990 Clean Air Act Amendments.

al., 1998). Both of these studies consider only the compliance cost of the proposed environmental regulations; and, neither considers the economic cost from a welfare theoretic perspective. Also, neither of these studies considers the benefits of the regulation in an economic metric comparable to costs.

The purpose of this study is to analyze the separate and combined effects of retail restructuring of electricity markets and new NO_X regulations applied to the electric power sector. We evaluate these effects from the broad standpoint of economic welfare. The measures employed are changes in customer and producer surplus in the electric power industry, and the monetary value of changes in health effects stemming from changes in NO_X emissions that are likely to result from these regulatory initiatives. The study employs an electricity market equilibrium model called HAIKU to simulate pre- and post-retail restructuring scenarios in combination with different environmental policy scenarios posited to occur by the year 2003. The emission changes that are projected are fed into the Tracking and Analysis Framework (TAF) to model atmospheric dispersion, health effects and health valuation.

The findings suggest that customer and producer surplus benefits substantially outweigh health damages from the slight increases in NO_X emissions that can be expected from retail restructuring. On the other hand, NO_X emission reductions enforced under an average cost pricing scenario (traditional cost of service regulation) would lead to customer and producer surplus losses that are only slightly less than their environmental benefits.

However, the NO_X emission reductions are less costly in terms of foregone customer and producer surplus when initiated in a restructured electricity industry. In this institutional setting, the additional effect of policies enforcing NO_X reductions is positive and substantial. Hence,

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[2] "RDI says new emission rules will cost utilities $21.8 billion over next 10 years," *Electric Utility Week*, October 26, 1998, p. 10.

retail restructuring has potentially important positive environmental benefits because it improves the affordability of NO_X emission reductions. Finally, the study finds that allowing NO_X trading, as opposed to imposing uniform performance standards, can lead to a $200 million increase in consumer and producer surplus in electricity markets with virtually no change in aggregate health related benefits.

The remainder of this report is organized as follows. The next section briefly describes the two models used in this study - the HAIKU electricity market model and the Tracking and Analysis Framework (TAF) health benefits model. We also describe how these models are used to calculate measures of economic welfare. Sections III and IV describe the electricity restructuring scenarios and the environmental policy scenarios analyzed in this study. Section V presents the results and section VI concludes. An appendix provides further detail on the modeling structure.

II. The Modeling Framework

This study employs two models to simulate the impacts of retail restructuring and new NO_X regulations on electricity customers, electricity suppliers and environmental quality. This section introduces these models and explains how each model contributes to the calculation of the net economic welfare impacts of retail restructuring and changes in environmental regulation.

The HAIKU Model

The HAIKU Model is a simulation model of regional electricity markets and inter-regional electricity trade with a fully integrated algorithm for NO_X emission control technology choice, constructed with the *Analytica* modeling software. The model can be used to simulate changes in electricity markets stemming from public policy associated with increased competition or environmental regulation. The model simulates electricity demand, electricity prices, the composition of electricity supply, inter-regional electricity trading activity among NERC regions, and emissions of key pollutants such as NO_X and CO_2 from electricity generation. The model can also be used to identify the NO_X emission control technologies on generators that achieve specified target levels of emissions under various environmental policies (technology-based policies, emissions taxes or regional emissions trading).

Two components of the HAIKU model are the Intra-regional Electricity Market Component and the Inter-regional Power Trading Component. The Intra-regional Electricity Market Component solves for a market equilibrium identified by the intersection of electricity demand and supply curves for each of three time periods (peak, middle and off-peak hours) in each of three seasons (summer, winter, and spring/fall) within each of 9 NERC regions.[3] The Inter-regional Power Trading Component solves for the level of inter-regional power trading necessary to equilibrate regional electricity prices (gross of transmission costs and power losses), but allowing for price discrimination in favor of native customers. These inter-regional transactions are constrained by the assumed level of available inter-regional transmission capability as reported by NERC. Each of these components is described in more detail in the Appendix.

The electricity demand functions from the intra-regional market component are used to calculate partial equilibrium changes in customer surplus for each region. In a partial equilibrium setting, the surplus for residential customers is calculated as the area under the demand curve less revenues. However, commercial and industrial customers consume sixty percent of the electricity sold in this country. Absent a detailed sectoral model of the downstream product markets or a general equilibrium model of the economy, it is an open question to what extent changes in customer surplus for these classes of customers are actually passed on to final consumers. Depending on the market structure and nature of pricing in downstream markets, and on the elasticity of demand for products and services in these markets, total consumer surplus could be greater or less than surplus associated with the commercial and industrial customers in the electricity market. Nevertheless, rather than ignore changes in customer surplus for these classes of customers, we report changes in total “customer surplus” for all customer classes. Changes in residential customer surplus typically account for 39% of changes in total customer surplus.

Producer surplus is the difference between revenues and costs, both outputs of the HAIKU model. In the baseline market structure scenario most of the country is modeled as average cost pricing, and for these regions this difference should be zero by construction. Nonzero producer surplus should characterize only the regions that are modeled as already having embraced retail competition in the baseline.

In the market restructuring scenarios, all of the country is assumed to practice marginal cost pricing. The issue of stranded costs is addressed explicitly by allowing for some fraction of stranded cost recovery. The current version of HAIKU takes investment and retirement as parametric, so we rely on estimates of stranded costs that have been developed in other studies under comparable assumptions to measure changes in producer surplus resulting from the introduction of competition.

The change in producer surplus resulting from the introduction of new NO_X restrictions can be calculated using the HAIKU model because investment in NO_X control technologies is determined endogenously. Under a particular market structure assumption (e.g. average cost

[3] The current version of the HAIKU model includes the 9 NERC regions: NPCC, MAAC, ECAR, SERC, MAIN, MAPP, SPP, ERCOT and WSCC, as they were defined in 1997. Recently, Florida has split from SERC to form its

pricing or marginal cost pricing), the model captures the relevant changes in producer behavior and calculates changes in revenues and costs to provide an estimate of changes in producer surplus.

The HAIKU model also calculates emissions of NOx, as well as other pollutants, from the electricity sector under different market structure and environmental policy scenarios. Changes in NO_X emissions resulting from retail restructuring or new environmental restrictions serve as inputs to the TAF health benefits model described next.

The Tracking and Analysis Framework

The Tracking and Analysis Framework (TAF) is used to translate the effects of changes in emissions into changes in human health. TAF integrates pollutant transport including formation of secondary particulates but excluding ozone to calculate human health effects and valuation of changes in health status, aggregated at the state level.[4]

TAF includes a separate Health Effects Module and Health Benefits Module, both of which are described in detail in the Appendix. The Health Effects Module is designed to estimate the changes in health status resulting from changes in air pollution concentrations. Impacts are expressed as the number of days of acute morbidity effects of various types, the number of chronic disease cases, and the number of statistical lives lost to premature death. The model output corresponds to change in the annual number of impacts of each health endpoint.

From an economic perspective, values are measured by how much of an asset or service individuals are willing to sacrifice in order to obtain or preserve another. The Health Valuation Module assigns monetary values taken from the environmental economics literature (e.g., Lee et

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own NERC region, FRCC, but this region is included in SERC for this analysis.

[4]TAF was developed on behalf of the National Acid Precipitation Assessment Program (NAPAP) using the *Analytica* modeling platform (Bloyd et al. 1996). TAF also accounts for visibility and aquatic effects which are not included as part of this study.

al. 1994) to the health effects estimates produced by the Health Effects Module. The benefits are totaled to obtain annual health benefits for each year modeled.

III. Market Structure Scenarios

The ultimate effect of electric power industry restructuring on consumer and producer surplus in electricity markets and on environmental quality and associated health benefits will depend on a number of factors. Restructuring is expected to lead to greater efficiencies in the generation sector that ultimately should translate into lower prices for consumers. The effect of restructuring on existing electricity producers will depend in part on the provisions that are made for the recovery of stranded costs.

The health effects of electricity restructuring appear more uncertain both with respect to their direction and relative order of magnitude. Some of the expected changes arising from restructuring are likely to lead to higher emissions of NO_X and therefore negative health benefits. For example, higher levels of electricity consumption in response to lower electricity prices could result in higher emissions than would have occurred absent restructuring. On the other hand, restructuring also is expected to result in efficiency improvements at existing generating facilities such as declines in heat rates that could reduce emissions yielding positive environmental benefits.

A priori, the characteristics of the post-restructuring electricity industry and market are highly uncertain. We characterize that uncertainty in a limited fashion by considering two different restructuring scenarios. One represents relatively moderate impacts of restructuring on a variety of technological parameters and market institutions; and, another represents more dramatic impacts. These two scenarios are called “Moderate Restructuring” and “Aggressive

Restructuring." These scenarios are contrasted to an Average Cost Baseline scenario and all three scenarios are set in the year 2003.

Table III.1 contains an overview of the assumptions that characterize each market structure scenario. Each scenario is defined by a number of technological and demand-related parameters that are expected to change as a result of restructuring. The technological parameters that vary across scenarios include: the rate of retirement and new investment in fossil-fueled generating units, the rate of retirement of nuclear power plants, the reduction in unscheduled outages, the rate of improvement in the availability factor (reduction in scheduled outages), the heat rate and operating cost at existing plants, and the rate of growth in transmission capability. The demand-related parameters include the method of determining prices and the extent of stranded cost recovery. The subsequent three sub-sections describe the three market structure scenarios we investigate.

	Baseline ***(incorporates wholesale competition)***	***Retail Restructuring with Moderate Efficiency Effects***	***Retail Restructuring with Aggressive Efficiency Effects***
Pricing Assumptions			
Stranded cost recovery	90% recovery in regions (NPCC and WSCC) with competition	90% recovery (rest largely mitigated)	75% recovery (rest largely mitigated)
Method of calculating prices	average cost pricing under traditional rate design by customer class (time of day pricing for industrials only) (except in NPCC and WSCC)	variable cost pricing of generation with substantial fixed cost recovery (see above); time of day pricing for industrials only	variable cost pricing of generation with limited fixed cost recovery (see above) and time of day pricing for all customer classes
Technology Parameters			
Fossil Steam Unit Retirements	based on AEO 98 reference case (RC) aggregate retirement of 50.8 GW by mid 2000's; replace by mix of coal and gas per AEO 98	accelerate fossil steam retirements from AEO 98 RC to 53.5 GW total by mid 2000's; replace by mix of coal and gas per AEO 98	accelerate fossil steam retirements from AEO 98 RC even more to 56.3 GW total by mid 2000's; replace by mix of coal and gas per AEO 98
Nuclear Unit Retirements	based on AEO 98 RC; 9.6 GW retired nationally	1/2 of AEO 98 "low nuclear case"; 16.2 GW retired nationally	full AEO 98 "low nuclear case"; 22.8 GW retired nationally

Table III.1 Assumptions characterizing different market structure scenarios.

	Baseline ***(incorporates wholesale competition)***	***Retail Restructuring with Moderate Efficiency Effects***	***Retail Restructuring with Aggressive Efficiency Effects***
Technology Parameters			
Net New Investment in Generating Capacity	based on AEO 98 RC; 98.3 GW added nationally; 71% gas turbine (GT), 22% combined cycle (CC), 7% scrubbed coal	91.7 GW added nationally (lower net investment due to higher nuclear retirement) (same technology percentages apply)	based on 75% of AEO 98 RC; 73.2 GW nationally (same technology percentages apply)
Rate of Improvement in Maximum Capacity Factor	AEO 98 RC assumes 82% max. capacity factor for steam units beginning in 1998; we assume 82.6%	3% improvement over forecast period due to consolidation of scheduled outages and reduction of forced outages	5% improvement over forecast period due to consolidation of scheduled outages and reduction of forced outages
Rate of Improvement in Coal-Fired Unit Heat Rate	none per AEO 98 RC	2% reduction in average heat rate over forecast	4% reduction in average heat rate over forecast
Improvement in Fossil Generating Unit Operating Costs	18% decline for O&M and G&A over entire forecast period (AEO 98)	25% decline in O&M and G&A over entire forecast period	35% decline in O&M and G&A over entire forecast period
Transmission Capacity Growth (Inter-region transmission capacity defined as .75*season-specific FCTTC in 1997)	7.5% growth over forecast period	24% growth over forecast period	43% growth over forecast period

Table III.1 Assumptions Characterizing Different Market Structure Scenarios (cont'd).

Baseline Scenario

A defining feature of electricity restructuring is the institution that governs the pricing of electricity. In the baseline scenario we assume that the electricity market continues to be predominantly served by regulated entities that price at average cost. In this case the penetration of retail competition and associated marginal cost pricing of electricity is limited to the two regions of the country that are already well on their way toward retail competition: NPCC and WSCC.[5] In the two regions that have marginal cost pricing, we assume that 90% of stranded costs (the portion of annualized fixed costs for sunk investments not recovered through the market price) will be recovered in electricity rates through access charges spread uniformly over all kWh sales. We also assume that only industrial customers have access to time-of-day pricing of electricity.

The technology assumptions for the average cost baseline including the assumptions regarding fossil steam unit and nuclear unit retirement as well as investment in new capacity are specified parametrically and taken largely from the 1998 Annual Energy Outlook ("AEO 98") (EIA, 1997) reference case.[6] The AEO 98 reference case retires existing generating units as scheduled, plus all other generating units with operating costs in excess of 4 cents per kWh evenly over a ten year period. In our baseline scenario, we adopt the AEO 98 retirement assumptions of 50.8 GW of fossil steam capacity by 2003, replacing it with a mixture of 7% scrubbed coal-fired and 93% gas-fired capacity. We also assume that 9.6 GW of nuclear capacity will be retired nationally. In addition to the capacity necessary to replace retirements,

[5] As of September of 1998, PUCs, state legislatures or both in all of the states of NPCC (which includes all of New England and New York State) had decided to implement retail competition by or before the middle of the next decade, the time period modeled in this study (The Vermont State Corporation Commission's restructuring plan requires legislative approval which is still forthcoming). In the WSCC, the states of California, Nevada, Montana and Arizona ,which constitute well over 50% of the electricity consumption in the region, have all either already implemented retail competition (California) or are expected to have done so by the middle of the next decade.

we adopt the AEO 98 assumptions that 98.3 GW of net new generating capacity will be added nationally with 71% gas turbine, 22% gas-fired combined cycle and 7% scrubbed coal-fired capacity.

For the baseline scenario, we adopt the AEO 98 assumption that the availability factor of existing fossil fuel units will not improve over time.[7] We also adopt the AEO assumption that recent declines in O&M costs at utility generators will continue into the future producing an 18% decline in O&M costs between 1995 (the year of our data) and 2003. We also assume that the recent 1.2% per year rate of growth in overall transmission capability will continue into the future yielding a 7.5% cumulative increase in transmission capability between 1998 (the year for which we have data) and 2003.[8]

Moderate Restructuring Scenario

This scenario adopts a variable cost pricing approach to electricity pricing for all NERC regions. The generation portion of the electricity price is defined by marginal cost (or, in the absence of time-of-day pricing, the weighted average of marginal costs that obtain across load blocks within a season) while the transmission and distribution portion of price is still defined on the basis of average cost. Time-of-day pricing remains available only to industrial customers. The short-run price impact of allowing competition on electricity prices is muted somewhat by the assumption that 90% of the utilities' stranded costs are recovered in retail prices. In the case of electricity traded between regions, stranded cost recovery is applied in the importing region.

[6] The EIA only reports national retirements by capacity type in the published AEO 98 report. We obtained a NERC regional breakdown of retirement data from the EIA.

[7] In HAIKU, the maximum capacity factor is defined at the model plant level by combining information on planned and unplanned outage rates by technology from the NERC GADS data base (NERC 1997). We assume that about 10% of planned outages occur in the summer, about 25% in the winter and about 65% in the Spring/Fall. Unplanned outages are allocated equally to all seasons according to the season's length. Using this method, the availability factor for a steam-fired generator in 1998 is 82.6% which is approximately equal to the 82% level assumed in the AEO 98.

[8] This estimate comes from the EPA's comments on the FERC EIS of Order 888 (EPA 1996).

Compared to the baseline scenario, the retail restructuring scenario assumes more aggressive retirement of both fossil-steam units and of nuclear plants. Under this scenario, 50% of the remaining quantity of fossil capacity with costs in excess of 4 cents per kWh are assumed to retire by 2003 bringing total fossil retirements to 53.5 GW. Nuclear retirements are pegged at a level that results in a level of nuclear capacity half way between that assumed under the AEO 98 reference case and that assumed in the AEO 98 "low nuclear" scenario. Net additions to capacity are somewhat lower as a result of this increased level of nuclear retirement, but the technology and fuel composition of replacement and net new capacity is the same as in the baseline.

This scenario also assumes that retail restructuring will lead to reductions in plant outages, improvements in heat rates and more aggressive reductions in operating costs compared to the baseline scenario. Specifically, we assume that reductions of scheduled and forced outages will lead to a 3% improvement in availability factors over the forecast period. We also assume that as a result of increased competitive pressures, heat rates will improve on average by 2% and operating costs at all existing units will fall by 25%, 7% more than under the baseline. Transmission capability is also expected to grow by 16.5% more under moderate restructuring, resulting in a 25% increase in transmission capability between all NERC regions over the forecast period.

Aggressive Restructuring Scenario

Under this scenario, retail competition and time-of-day pricing of electricity are assumed to be pervasive. It is assumed that all customer classes in all NERC regions buy electricity in competitive markets and face time-varying electricity prices. The amount of stranded costs is greater in the Aggressive Restructuring scenario than in the Moderate Restructuring scenarios due to the pace of technological change, the pace of retirement and investment, and several other factors. The impacts of competition on retail prices are also larger under this scenario due to the assumption that only 75% of stranded costs are recovered. Again, in the case of electricity traded between regions, stranded cost recovery is applied in the importing region.

This scenario assumes more aggressive retirements and less aggressive investment, due in part to higher expected capital costs. Under aggressive restructuring, the total amount of fossil generation with operating costs in excess of 4 cents per kWh is assumed to retire by 2003 resulting in 5.5 additional GW of retirement relative to the baseline scenario. In addition, nuclear retirements are assumed to mirror those assumed in the AEO 98 "Low Nuclear" scenario yielding a total of 22.8 GWs of retirement nationally, 13.2 GW more than in the baseline. Net new investment is about 75% of the level assumed in the baseline scenario due largely to a reduction in reserve margins.

Improvements in generating unit performance and cost, and growth in transmission capability are also larger under aggressive restructuring than under moderate restructuring or the baseline. A 5% improvement in availability factors is assumed and average heat rates at fossil-fired units are assumed to improve by a full 4% by 2003.[9] Also, unit-level operating costs (excluding fuel costs) are assumed to fall by 35% between 1995 and 2003.[10] Inter-regional transmission capability is assume to grow by 43% which is consistent with the high transmission growth scenario in the FERC EIS (1996) and in Palmer and Burtraw (1997). This higher rate of transmission capacity growth is almost twice as fast as that assumed under moderate restructuring and nearly 6 times as fast as that assumed under the baseline.

[9] The DOE policy office also assumes a 4% improvement in average heat rates in its analysis of the President's Comprehensive Electricity Competition Plan which envisions nationwide adoption of competitive retail electricity markets by 2003. Roberts and Goudarzi (1998) find that average heat rates could improve by as much as 8% to achieve industry best practice.

IV. Environmental Policy Scenarios

A second focus of this study is on the relationship between electricity restructuring and NO_X emissions from the electric power sector, and new proposed environmental policies to limit emissions. Increased competition and increased inter-regional power trading is expected by some to lead to increases in NO_X emissions, at least in the short run. However, new environmental regulations proposed to take effect over roughly the same time period could lead to substantial reductions in NO_X emissions from the electric power sector while imposing greater costs on the electricity sector and consumers. Some proposals would use the occasion of electricity restructuring to expand environmental regulations to ensure that NO_X emissions do not increase as a consequence of restructuring.

Several proposals have been put forward. One current proposal is the so-called "NO_X budget" specified in a memorandum of understanding (MOU) among members of the northeastern Ozone Transport Commission (OTC). The MOU establishes a budget for NOX emissions from large stationary sources for the northeastern states in an 11 state region and the District of Columbia stretching from the District to Maine.[11] Another proposal is the EPA's Final Rule for Reducing Regional Transport of Ground-Level Ozone (September, 1998) that establishes seasonal (five-month) NO_X emission reduction targets for large stationary sources in an expanded set of 22 states (plus the District of Columbia) that lie east of the Mississippi (excluding Maine and Florida). The rule sets state-level NO_X emission budgets, but also encourages the states to develop a regional emissions allowance trading market to reduce the costs of achieving the required emissions reductions within the region. In addition, some of the proposed legislation now before congress that would establish retail electricity competition

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[10] EIA (1997) assumes a 40% decline in operating costs as a result of the move to retail competition over the same period.

includes provisions to require reductions in emissions of NO_X and other pollutants from existing generators. Other proposals that have been suggested would establish an "old source performance standard" (OSPS) by extending performance standards that are applied to new stationary sources to existing sources. This would essentially treat all sources in a comparable fashion with respect to an allowable emission rate, with or without the possibility for trading.

To capture the features of these various proposals, this analysis considers three environmental regulatory scenarios. One is a baseline that characterizes only the 1990 Clean Air Act Amendments (CAAA). The second is an old source performance standard (OSPS) requirement, *without* NO_X emission allowance trading, affecting all generators in the five eastern NERC regions (approximately equal to the 22 eastern states and DC). The third is a NO_X emission allowance trading regime (based on the quantity of NO_X emissions resulting from the OSPS regime) across generators in the same five eastern NERC regions. All of the environmental policy scenarios considered in this study assume a NO_X policy that is applicable year round. Relevant features of each of these scenarios appear in the following several paragraphs and are summarized in Table IV.1.

[11] The state of Virginia is part of the OTC, but they have not yet signed on to the MOU.

Scenario Name	NERC Regions Covered	NO_X Compliance Options	Average Emission Rate Goal	NO_X Trading?
1990 CAAA Baseline	All.	Combustion controls only; see Appendix A.	varies by technology; see Appendix A.	NO.
OSPS in Eastern States	NPCC, MAAC SERC, ECAR MAIN.	Post combustion options include SCR, SNCR, and Hybrid methods.	.15 lbs. per mmBtu heat input.	NO.
NO_X Allowance Trading in Eastern States	NPCC, MAAC SERC, ECAR MAIN.	Post combustion options include SCR, SNCR, Hybrid methods, and allowance purchases.	.15 lbs. per mmBtu heat input.	Yes, among all utility sources in region.

Table IV.1 Overview of environmental policy scenarios.

1990 CAAA Baseline

In this scenario we assume that by 2003 all coal-fired generating units have adopted relevant controls necessary to comply on a unit-by-unit basis with emission reductions required under phase II of Title IV of the 1990 CAAA.[12] This is a fairly restrictive representation of strategies to achieve these goals since the EPA actually does allow interstate averaging of NO_X emission across facilities owned by the same utility. This scenario does not incorporate additional NO_X controls required under the OTC MOU. Also, these controls are based on emission rates applicable to individual units. Since there is no emissions cap, total emissions grow with increases in generation or the addition of new capacity, which is assumed to comply with NSPS for NOx.

[12] For a discussion of the necessary controls, see Appendix A in Burtraw, Palmer and Paul (1998).

OSPS in Eastern States (without trading)

This scenario imposes an emission rate standard of 0.15 lbs. of NO_X per mmBtu on all existing fossil steam generators in the five eastern NERC regions (NPCC, MAAC, SERC, ECAR and MAIN) which is applied throughout the year. This group of NERC regions corresponds closely to the 22 states included in the ozone transport rulemaking region.[13] The emission rate standard is implemented in the model by forcing all fossil-fuel boilers in these five regions to adopt the least expensive NO_X control technologies that will bring them to a NO_X emission rate no greater than 0.15 lbs. of NO_X per mmBtu. For those units that are unable to reduce NO_X emissions to that level, we require them to reduce as much as possible. All of these additional controls are post-combustion controls and are added on top of the controls assumed in the 1990 CAAA baseline scenarios. We assume that existing generators will be able to recover the cost of these additional controls. Even under competition, they are assumed recoverable as a part of a stranded cost recovery package.[14] The resulting level of NO_X emissions from the electricity sector in this eastern region (and across the country) will differ across the three market structure scenarios because of the variation in generating plant performance and costs, in electricity demand, and in transmission capability.

NO_X Allowance Trading in Eastern States

The level of the NO_X cap under each market structure scenario (baseline and retail restructuring) is determined from the prior set of OSPS scenarios without trading. In this scenario electricity generators (model plants) are allowed to trade emission allowances. The model identifies a solution wherein plants with high marginal abatement costs obtain allowances

[13] The five NERC regions exclude from the 22 states region a small portion of western Missouri. It includes the eastern half of Mississippi, Florida, Vermont, New Hampshire and Maine, which are not part of the 22 state region. However, the three included New England states are part of the eastern region covered by the OTC MOU and the reconciliation of these two programs may involve their ultimate participation.

from plants with low marginal abatement costs, and plants with low marginal abatement costs "over-comply" to free up the allowances that are transferred. The cost of investment in NO_X abatement and additional operating costs of generation are reflected in the dispatch order by increases in marginal cost, allowing the utilization of facilities to adjust as another means of compliance. A third means of compliance can occur through reduced electricity demand, to the extent NO_X control increases the price of electricity. Hence, the model identifies a least cost solution for obtaining the specified level of NO_X emissions, with the cost born by NO_X abatement, changes in dispatch order, and changes in demand. This approach will yield an estimate of control costs that is biased low to the extent emission allowance markets work less efficiently than a textbook model would suggest. There is evidence of this in the context of SO_2 controls under cost of service regulation (Carlson, *et al.* 1998). This bias should be less apparent as we move into retail restructuring.

While the approach to modeling NO_X trading does not differ across the different market structure scenarios, the way NO_X allowance costs and other NO_X control costs affect the price of electricity does vary across scenarios. Under average cost pricing (baseline), we assume that NO_X allowances are distributed for free (grandfathered) and that state regulatory commissions would not allow utilities to keep any profits associated with allowance transactions. That is, allowances are valued at original cost of zero (rather than market value) for cost recovery purposes. Also, utilities would be allowed to recover the cost of permits purchased for compliance but this is offset by revenue accruing to the selling utility that is used to offset investment in emission control at its sites. This means that by allowing utilities to recover only

[14] Unlike other stranded costs, we assume that NO_X control costs are fully recovered under an OSPS regulation without emissions trading.

the costs of emission control equipment and its operation, the total cost recovery for NO_X a trading program is accurate for the industry as a whole.

Under both retail competition scenarios, we assume that electricity generators will fold the full opportunity cost of NO_X allowances into the price of electricity and thus prices charged to electricity customers will reflect this opportunity cost. Therefore, while NO_X trading should reduce the aggregate compliance costs of achieving the NO_X emissions cap, trading could have a greater impact on electricity prices, at least under competitive electricity pricing, than a uniform emission rate standard. Because the granting of allowances at zero cost based on a fraction of historic emissions constitutes a significant compensation to the utility, we do not allow for recovery of fixed NO_X control costs under the permit trading regime.[15]

V. Results

The HAIKU and TAF models are used to estimate the impacts of restructuring and new NO_X policies. First we present the impacts of restructuring in the absence of additional NO_X policies. These impacts include effects on the price of electricity, the quantity of generation, and tons of NO_X emissions. Then we evaluate these impacts by calculating the associated changes in economic welfare that are expected to result. Next, we discuss the impacts and the welfare implications of new NO_X policies and the implications of allowing NO_X trading. Last, we discuss the impacts and welfare effects of combining restructuring and NO_X policies. All results are for the year 2003 and all dollar amounts are reported in 1995 dollars.

The Impact and Welfare Effects of Retail Restructuring

Retail restructuring is expected to lower the average price of electricity and increase the quantity of electricity generation. Table V.1 shows that the average national price should decline by just over 6% for the moderate restructuring scenario and nearly 11% for the aggressive scenario.[16] These decreases in electricity prices yield increases in electricity demand and in generation. The retail restructuring scenarios also assume increases in transmission capability and accelerated rates of retirement for nuclear and old coal-fired facilities, which would be likely to produce changes in the composition of electricity generation even in the absence of an increase in demand. All of these influences combine to produce the 1.8% and 3.2% increases in national electricity generation reported in the second row of Table V.1.

	Baseline		**Moderate**		**Aggressive**	
Average Price *(cents/kWh)*	6.79	NA	6.36	-6.3%	6.05	-10.8%
Total Generation *(TWh/yr)*	3,464	NA	3,526	1.8%	3,575	3.2%

Table V.1 Impact of Retail Restructuring scenarios on national electricity markets and percent change from market structure baseline.

The changes in generation are expected to result in changes in NO_X emissions, and these estimated changes are summarized in Table V.2. This table reveals that restructuring will increase emissions in the year 2003, and increase more with aggressive restructuring. In this relatively short time horizon the accelerated retirement of inefficient coal facilities will not offset the increased use of other older coal generators due to expanded transmission capability and higher electricity demand. Without new NO_X regulation, we expect electricity restructuring to result in up to 4% more NO_X emissions from the electric power sector nationally per year. The

[15] To both give the utilities valuable NO_X permits for free and to allow full recovery of NO_X control costs creates potentially large profit making opportunities for utilities that install large amounts of control equipment (with full cost recovery) and then sell permits and keep the revenue.

[16] These estimates are within the range of prior studies. A recent analysis of the Clinton Administration's Comprehensive Electricity Competition Act (DOE 1998) finds that national average electricity prices are 12% lower in 2010 as a result of the plan. In another study of the price impacts of electricity restructuring, which assumes that

entirety of this increase will occur in the five eastern NERC regions (NPCC, MAAC, SERC, ECAR and MAIN) where NO_X emissions will increase by 2.8% under moderate restructuring and 5.6% under aggressive restructuring. Thus NO_X increases are greater than average in the densely populated eastern section of the country.

Geographic Region	Baseline		Moderate		Aggressive	
Nation	4,605	NA	4,683	1.7%	4,783	3.9%
East	3,202	NA	3,291	2.8%	3,380	5.6%

Table V.2 NO_X emissions *(thousand tons/year)* and percent change for industry from market structure baseline given 1990 CAAA scenario.

The impacts we discover are listed in the disparate metrics of cents, kilowatt-hours and tons. To compare these impacts we evaluate the changes in the single measure of economic welfare. Changes in price and consumption in the electricity market lead to substantial gains in customer surplus. Table V.3 indicates that total customer surplus gains range from \$14.3 billion with moderate restructuring to roughly \$24.9 billion with aggressive restructuring. In both cases, roughly 39% of the customer surplus accrues to residential customers. These gains in customer surplus represent a substantial fraction of total electric industry revenue. Under the baseline scenario, total industry revenues for 2003 are \$228 billion and the gains to electricity customers from restructuring represent over 6% of that total revenue under the moderate restructuring scenario and over 10% under the aggressive scenario.

While restructuring promises gains to customers, it is likely to lead to losses for some existing electricity suppliers and for the industry as a whole as many producers will be unable to recover the costs of many generating assets (or of some outstanding power purchase contracts) at

only the 25-30 higher cost states allow retail competition, SAIC (1998) predicts that the national average price level for 2005 will be 6.2 cents per kWh (1996$).

competitive electricity prices. We draw on estimates of stranded costs under comparable market structure scenarios as a basis for evaluation of changes in producer surplus. We combine these estimates with our assumptions about the aggressiveness of the efficiency effects of restructuring and about the allowed rate of stranded cost recovery. Table V.3 indicates that the decline in producer surplus ranges from $1.3 billion to $4.4 billion under the alternative scenarios.[17] These values are significant, but small relative to the expected gains in customer surplus. The sum of customer and producer surplus changes is positive and substantial, ranging from $13 billion to $20.5 billion.

The increased NO_X emissions reported in Table V.2 are expected to lead to health damages that further offset the customer surplus gains. Table V.3 reports the monetary value of expected health damages due to additional NO_X emissions and contrasts these with the change in customer surplus and producer surplus. The value of the increased health damages from NO_X emission changes are two orders of magnitude less than the gains in customer and producer surplus resulting from restructuring.

	Moderate Restructuring	Aggressive Restructuring
Customer Surplus Component	14,331	24,858
Producer Surplus		

[17] The producer surplus impacts reported in this table are calculated as follows. For moderate restructuring we adopt the $122 billion dollar estimate of stranded cost reported by Resource Data International (RDI 1996). Assuming that those stranded costs are incurred over a 20 year period, we calculate the annualized losses associated with this stock of stranded costs assuming a 9% annual interest rate. This yields a total annual flow of stranded costs equal to $ 13.36 billion. In our moderate restructuring case, we assume that 90% of total stranded costs are recovered through prices. Therefore, we assume that lost producer surplus associated with moderate restructuring is equal to 10% of this $13.36 billion annual flow or $ 1.336 billion. Under aggressive restructuring, electricity prices are expected to be even lower and therefore stranded costs should be even higher. To construct an upper bound on stranded cost we inflate the $122 to $160 billion (The ratio of $160 to $122 is equal to the ratio of the high estimates of stranded cost to the expected levels of total stranded costs reported in an EIA study of the impacts of restructuring on electricity prices (EIA 1997).) We then apply the same procedures to get an annual flow of stranded cost of $17.53 billion per year. Under aggressive restructuring we assume that 75% of stranded cost is recovered in electricity prices which leaves the remaining 25% or $4.383 billion as lost producer surplus.

Component	-1,336	-4,383
Sum of Customer and Producer Surplus	12,995	20,475
NO_X Health Benefits	-65	-136

Table V.3 Customer and producer surplus and NO_X health damages from retail restructuring relative to the baseline market structure (*million 1995$*). Negative health benefits indicate damages.

The Impact and Welfare Effects of New NO_X Emission Policies

The previous section discussed results of alternative market structure scenarios under the single environmental policy regime of full compliance with Title IV of the 1990 Clean Air Act Amendments. In this section we explore the potential impact of alternative environmental policies regarding NO_X emissions from electricity generation. We compare the change in emissions that can be expected from NO_X emission reductions with changes in electricity prices and generation. We also compare the monetary value of changes in health status associated with changes in NO_X emissions with producer and customer surplus to obtain a measure of economic welfare changes.

Table V.4 presents the effects of an annual NO_X trading program in the eastern 22 states and DC on total electricity sector NO_X emissions nationwide and in the east. Under both the baseline (average cost pricing) and the moderate restructuring market structures the emission reductions are in excess of 50% nationwide and approximately to 75% in the targeted region. The percent change in each case is relative to the environmental baseline (1990 CAAA) for the specified market structure. Hence, the comparisons in the two sets of columns are relative to different baselines since total NO_X emissions under the 1990 CAAA depend on the market structure assumption.

Geographic Region	Baseline Market Structure		Moderate Restructuring	
Nation	2,208	-52.1%	2221	-52.6%
East	805	-74.9%	821	-75.1%

Table V.4 Annual NO_X emissions (*thousand tons/year*) with NO_X trading in the east, and percent change for industry from 1990 CAAA scenario under two alternative market structure scenarios.

The human health benefits associated with these declines in NO_X emissions are also substantial. The value of health benefits under emissions trading for the baseline and moderate restructuring scenarios are presented in Table V.5. These benefits are compared with those that would obtain under an old source performance standard (OSPS) that achieved the same aggregate emission reductions without trading. The opportunity to trade emission allowances leads to virtually identical health benefits as the OSPS regime under the baseline and moderate restructuring scenarios. The slight changes result from a shift in the regional distribution of emissions that arise with NO_X trading.[18]

NO_X Policy Regime	Baseline Market Structure	Moderate Restructuring
Trading	1,856	1,908
OSPS	1,858	1,912

Table V.5 National health benefits of NO_X policies affecting five eastern NERC regions (*million 1995$/year*).

The HAIKU model allows us to compare estimates of the health benefits with estimates of the costs of achieving these emission reductions to do a first-order cost-benefit analysis of these policies. The traditional approach to measuring the costs of environmental regulations is to use estimates of the out-of-pocket costs of complying with the regulation. However, these costs do not reflect the full economic costs of the regulation. One measure that is closer to the full economic costs is an estimate of the sum of customer and producer surplus losses in electricity markets associated with the introduction of the environmental policy. We look at both types of cost estimates below.

In order to calculate the impacts of the NO_X policies on producer and consumer surplus, we must calculate the effects of these policies on electricity prices. Table V.6 shows that the NO_X policies result in fairly small changes in electricity prices, always less than 1%. The table also shows that the combined flexibility afforded by retail restructuring and allowing NO_X trading leads to the smallest impact on electricity prices.

NO_X Policy Regime	**Baseline Market Structure**		**Moderate Restructuring**	
Trading	6.84	0.8%	6.39	0.5%
OSPS	6.84	0.9%	6.42	0.9%

Table V.6 Average retail electricity price (*cents/kWh*) and percent change from 1990 CAAA baseline for two environmental scenarios, under two alternative market structure scenarios.

Table V.7 presents a comparison of the health benefits to two measures of the costs of the new NO_X restrictions in the East under a NO_X emissions trading program, under two alternative market structure scenarios. This table shows that under both the baseline market structure and the moderate restructuring case, the health benefits of the NO_X policy exceed either measure of the costs.

In comparing the two measures of cost, we note that under the baseline market structure, losses in surplus exceed control costs. In this case, most of the country practices average cost pricing, so changes in producer surplus are necessarily zero or small by construction. Hence, most of the difference stems from the loss of customer surplus resulting from increased price and

[18] For more information on these regional shifts, see Burtraw, Palmer and Paul (1998).

lower consumption of electricity. This illustrates the common criticism that measures of compliance cost do not equal economic cost, and in most cases are thought to under-represent full economic cost, because they fail to account for losses in consumer surplus.

Under the moderate restructuring scenario this comparison is reversed, and compliance costs exceed the measure of economic surplus. The reason is that under marginal cost pricing, compliance costs are not automatically passed through to consumers in setting the price of electricity, as is the case with average cost pricing. Instead, under marginal cost pricing, compliance costs are recovered only when the price of electricity reflects the marginal cost of compliance. This occurs only when the marginal generating unit in the dispatch order must engage in compliance activity (or use emission allowances in a trading program).[19]

In a marginal cost pricing scenario, the environmental regulation could lead to an effect on revenues that is greater or less than the cost of compliance, depending on the dispatch order of facilities. In the present example, it appears that producers fail to recover fully their compliance costs through marginal cost pricing, because, during a nontrivial fraction of the year the unit that is marginal has zero or relatively small compliance costs. This yields a smaller increase in electricity prices than under the baseline market structure. The lower price leads to greater generation and greater customer surplus (or smaller declines in customer surplus as a result of the environmental regulation), and the sum of changes in customer and producer surplus is less than compliance cost. Hence, in this case we find that compliance cost over-estimates the economic cost of the regulation.

	Baseline Market Structure	**Moderate Restructuring**
Health Benefits	1,882	1,908

[19] When the marginal unit faces regulatory compliance costs, there are two effects on price. One is direct compliance cost, and a second is the opportunity cost of permits used to cover emissions from that facility.

Two Alternative Measures of Cost:		
Compliance Costs	1,680	1,671
Losses in Customer and Producer Surplus	1,747	1,334

Table V.7 The benefits and costs of a NO_X trading program under two alternative market structure scenarios (*million 1995$*).

The main point to note in Table V.7 is the difference in cost between the two market structure scenarios. While NO_X policies have significant costs in both cases, the costs are substantially less in the moderate restructuring case. In a sense, one can conclude that environmental policy is less expensive with a restructured market. Meanwhile, benefits are slightly greater under moderate restructuring due primarily to the increase in emissions that would occur in the absence of a NO_X policy.

Table V.8 provides insight into how the benefits and costs would change if the OSPS approach were substituted for the NO_X trading approach, thereby eliminating the opportunity for emission allowance trading. The first row indicates that the health benefits of NO_X reductions are virtually identical under the two policies. Calculated from Table V.5, the health benefits from NO_X controls are $2 million (0.1%) greater with OSPS than with trading under the baseline market structure, and $4 million (0.2%) greater under moderate restructuring. However, the measures of the costs of the NO_X policy differ substantially under OSPS compared to trading. Using either measure of cost, Table V.8 indicates that an OSPS would cost over $200 million more than a program that relied on trading.

	Baseline Market Structure	**Moderate Restructuring**
Health Benefits	2	4
Two Alternative Measures of Relative Costs:		
Compliance Costs	201	220

Losses in Customer and Producer Surplus	243	219

Table V.8 The benefits and costs of OSPS compared to trading policies for NO_X emission reductions *(million 1995$)*.

NO_X Policies in a Restructuring Electricity Industry

The final question that we seek to address is how well NO_X policy is likely to perform in a restructuring electricity industry. We explore what happens to customer and producers surplus and to health benefits when we simultaneously impose moderate restructuring and a NO_X cap and trade program. This section reports on the results of that analysis.

	Baseline Market Structure 1990 CAAA Only	Moderate Restructuring NO_X Trading in East	Percent Change
Price *(cents/kWh)*	6.79	6.39	-5.9%
Generation *(TWh/yr)*	3,464	3,520	+1.6%
NO_X Emissions *(thousand tons/yr)*	4,605	2,216	-51.9%

Table V.9 Impacts of combining NO_X cap and trade with moderate restructuring scenario, compared to baseline environmental and market structure scenario.

Table V.9 reveals the changes in electricity price, electricity generation , and NO_X emissions from electricity generators associated with these changes in market and regulatory structure. Introducing the new NO_X restrictions simultaneously with retail restructuring has a slight dampening effect on the decline in electricity prices, but still yields an increase in electricity demand combined with a substantial decrease in total NO_X emissions.

The implications of these simultaneous changes are reported in Table V.10. The large drop in NO_X emissions leads to $1.8 billion in health benefits. The nearly 6% drop in price combined with the additional costs imposed by the new NO_X regulation result in a $1.7 billion drop in producer surplus. Customers gain the most from the move to competition. The small losses to electricity customers associated with the higher costs of the new environmental regulations are substantially outweighed by the gains from the price drop associated with the move to competition. Meanwhile, the health benefits are also substantial. The total change in welfare is estimated to be $13.5 billion.

Health Benefits	1,847
Customer Surplus Gains	13,394
Producer Surplus Gains	- 1,735
Net Increase in Welfare	13,506

Table V.10 Health benefits and economic surplus changes from introducing moderate restructuring combined with NO_X emissions cap and trade, compared to benchmark with baseline market structure and baseline environmental policy *(million 1995$)*.

VI. Conclusions

The debate surrounding restructuring of the electricity industry has been often acrimonious. A key point of contention has been the concern that gains that may be realized through lower electricity prices would be offset to an important degree by a deleterious increase in pollutant emissions.

This study looks at various impacts of retail restructuring of electricity markets and likely concurrent changes in environmental regulations. The findings are consistent with those of many previous authors who project that electricity pries will fall and consumption increase with restructuring, and that emissions of NO_X are likely to increase as well.[20] We also look at the role of NO_X policy taken in isolation from changes in market structure and find the converse. NO_X policy is likely to lead to an increase in electricity prices and a decrease in generation, as well as a decrease in NO_X emissions. Finally we examine the effects restructuring in tandem with new NO_X regulation.

Evaluation of these expected changes is difficult absent a single metric for comparison. We use the common metric of economic welfare to calculate changes in consumer and producer surplus and the monetary value of changes in health status predicted to result from these policies.

The study presents four main findings. First, we find that retail restructuring would produce combined customer and producer surplus benefits that substantially outweigh health damages from slight increases in NO_X emissions. The majority of these benefits accrue to customer groups, roughly in proportion to their share of electricity consumption.

Second, under the baseline market structure of average cost pricing for most of the nation, new NO_X emission reduction efforts lead to substantial losses in combined customer and producer surplus. These losses are only slightly less in magnitude than the public health benefits that would follow from emission reductions.

Our third finding concerns the confluence of restructuring and environmental policy. Under retail competition, new NO_X regulations are less costly in terms of foregone customer and producer surplus. Under this new market institution, the net impact of NO_X reductions on economic welfare is positive as the large health benefits from the emission reductions outweigh losses in combined customer and producer surplus. Furthermore, the economic cost of NO_X reductions are substantially less than in the baseline market structure of average cost pricing.

[20] See Lee and Darani (199), Center for Clean Air Policy (1996a, 1996b, 1996c), Rosen et al. (1995), EIA (1996).

Finally, we make the observation that using NO_X trading instead of a uniform emission rate standard (OSPS) to achieve substantial NO_X emission reductions in the eastern U.S. leads to annual economic welfare gains in excess of $200 million. These gains result from a decrease in the economic cost of compliance due to the flexibility afforded by an emission allowance trading program. In the aggregate, health benefits are virtually unchanged by a trading program, although some geographic redistribution of emissions and health benefits is expected.

Environmental considerations provide an important obstacle to restructuring the electricity industry. From the perspective of welfare economics, we find that the environmental costs of restructuring are likely to be swamped by the economic gains of restructuring. Nonetheless, these environmental concerns have a serious role in the political debate. This study finds that NO_X reduction policy is made less costly and the benefits are amplified in a restructured industry.

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Appendix: Details of the Modeling Framework

This analysis uses two models - The HAIKU Model and the TAF Health Benefits Model - to simulate the effects of different restructuring and environmental policy scenarios on a host of electricity market and environmental variables. Each of these models is described below.

The HAIKU Model

The HAIKU Model is a simulation model of regional electricity markets and inter-regional electricity trade with a fully integrated algorithm for NO_X emission control technology choice, constructed with the *Analytica* modeling software. The two components of the HAIKU model are the Intra-regional Electricity Market Component and the Inter-regional Power Trading Component.

Intra-regional Electricity Market Component

This model component uses a reduced-form dispatch algorithm to develop electricity supply curves for each NERC region during three time periods (peak, middle and off-peak hours) for each of three seasons (summer, winter, and spring/fall). The supply curves are constructed using information on capacity (net of planned and unplanned outages), operating and maintenance costs (including pollution control costs) and fuel costs for several “model plants” each of which represents a group of generating units aggregated by region, fuel type, technology and vintage classifications. The operation of model plants in each time period is determined according to a market equilibrium identified by the intersection of the supply and demand curves for that time period (and subsequent opportunities for inter-regional power trading that are described below). The market price of electricity is determined according to the specified regulatory institution in the scenario. Average cost pricing and marginal cost pricing can both be represented. Under marginal cost pricing, for example, the equilibrium price is equal to the sum of the market clearing price of electricity generation and the additional costs of transmission and distribution services, including intra-regional transmission losses.[21] The demand, supply and emissions components of this model and the underlying data are described in more detail next.

Demand

Using data from the U.S. Energy Information Administration (EIA), the demand component classifies annual electricity demand by three customer types (residential, commercial and industrial), by three seasons (summer, winter, fall/spring), and by three time blocks (peak, middle and off-peak hours). Demand within each block is represented by a price-sensitive demand function where each customer/season/time block is characterized by an elasticity value that is usually unique.

Supply

The model plants that populate the supply component of HAIKU are constructed using information at the generating unit level on generating capacity and engineering characteristics drawn from three different EIA databases: EIA 860, EIA 759 and EIA 767. This information is aggregated to the "model plant" level based on the fuel type, technology (including boiler type for some coal-fired boilers) and vintage of each unit. The model plant definitions used in this model are adapted from those developed by the U.S. EPA for the Clean Air Power Initiative project (EPA 1998). As a part of that project, EPA's contractor, ICF, Inc., developed prototypical operating cost information for each model plant category. This information is combined with regional fuel cost, the costs associated with endogenously selected NO_X control technologies (and, in the case of emission allowance trading, the cost of NO_X allowances) and unit availability (reflecting planned and unplanned outages) to develop regional supply curves. The geographic location of emissions are determined by portioning out total generation and total

[21] For purposes of setting electricity prices, intra-regional transmission losses are assigned to the exporting regions.

emissions from each model plant to its constituent plant locations according to each constituent plant's share of 1995 generation.

The version of the HAIKU model employed in this study does not incorporate endogenous investment and retirement decisions, except with respect to investments in NO_X control technology.[22] This means that the model in unable to shed light on how changes in electricity market policy or environmental policy will affect retirement of older generating facilities or investment in new generating facilities. However, the model does incorporate parametric assumptions about plant retirement and investment and these assumptions vary under different restructuring scenarios. Since this study looks at the effects of restructuring in the early part of the next decade (2003), it incorporates changes in the stock of generating capital currently planned or that are likely to take place in the interim, and these assumptions are varied within the analysis.

Emissions

The model contains emission factors for NOx, SO_2 and CO_2 for each model plant that is constructed using information from U.S. EPA and EIA on plant performance and total emissions. This project focuses primarily on NO_X emissions.[23] Information on the costs of NO_X emission control is obtained for all generating facilities and aggregated to the model plant level. NO_X control strategies are chosen endogenously and the costs of these controls feed into the calculation of NERC region-wide electricity supply functions. This interaction between endogenously chosen emission control costs and emission factors with electricity supply

[22] A longer-run version of the model that incorporates endogenous generating plant retirement and investment is currently under development.

[23] Electric power industry-wide emissions of SO2 are capped under Title IV of the 1990 Clean Air Act Amendments and CO2 emissions are a global environmental issue, that is outside the scope of this project.

illustrates the effect of alternative environmental policies on inter-regional power trading and other market outcomes, as well as their effect on emissions.

The effects of alternative environmental policies are indicated by changes in electricity prices, quantity of electricity produced, amount of electricity generated using each model plant technology and levels of emissions of NO_X and other pollutants by model plant and by region. Regional information on NO_X emissions are used as inputs to the TAF for calculation of health effects and health benefits.

Inter-regional Power Trading Component.

This model component solves for the level of inter-regional power trading necessary to equilibrate differences in regional equilibrium electricity prices (gross of transmission costs and power losses) across different NERC regions. These transactions are constrained by the assumed level of available inter-regional transmission capability as reported by NERC. This capability is assumed to grow at different rates under different market structure scenarios. Transactions are determined by the excess energy supply function for exporting regions and the excess energy demand functions for importing regions. The marginal cost of generation for export in supplying regions is determined after solving (or resolving) for equilibrium prices within the region. Hence, price discrimination is assumed in that native customers within a supplying region pay a different (lower) price for generation than customers in other regions that receive imports from the supplying region.

The Tracking and Analysis Framework

The Tracking and Analysis Framework (TAF) is used to translate the effects of changes in emissions on changes in human health. TAF is constructed with the *Analytica* modeling software and integrates pollutant transport including formation of secondary particulates but excluding ozone, human health effects, and valuation of benefits (Bloyd et al. 1996).[24] TAF was developed on behalf of the National Acid Precipitation Assessment Program (NAPAP). Each module of TAF was constructed and refined by a group of experts in that field, and draws primarily on peer reviewed literature to construct the integrated model. TAF was subject to an extensive peer review in December 1995, which concluded that "TAF represent(s) a major advancement in our ability to perform integrated assessments" and that the model was ready for use by NAPAP (ORNL, 1995).

TAF characterizes emissions, emission transport, atmospheric concentrations of pollutants and health effects at the state level. Changes outside the U.S. are not evaluated. The considerable uncertainty in parameters in each of the modeled domains and in the underlying scientific and economic literature is at least partly captured through Monte Carlo simulation, and has been explored elsewhere (Burtraw *et al.*, 1998; Sonnenblick and Henrion, 1997).

The Health Effects Module

The Health Effects Module in TAF is designed to estimate the health impacts of changes in air pollution concentrations. Impacts are expressed as the number of days of acute morbidity effects of various types, the number of chronic disease cases, and the number of statistical lives lost to premature death. The change in the annual number of impacts of each health endpoint is the output. Inputs consist of changes in ambient concentrations of SO2 and NOx, demographic information on the population of interest, and miscellaneous additional information such as background PM10 levels for analysis of thresholds.

The module is based on concentration-response (C-R) functions found in the peer-reviewed literature. The C-R functions are taken, for the most part, from articles reviewed in the U.S. Environmental Protection Agency (EPA) Criteria Documents (see, for example, USEPA

[24] TAF also accounts for visibility and aquatic effects which are not included as part of this study.

1995). These documents are outcomes of a recurring comprehensive process initiated by the Clean Air Act and its Amendments for reviewing what is known about the health effects of the so-called "criteria" air pollutants. The Health Effects Module contains C-R functions morbidity and mortality endpoints for PM10, total suspended particulates (TSP), SO2, sulfates (SO4), NO2, and nitrates (NO3). Since nitrates are particulates, and no independent effect of nitrates on health has been established, they are treated as a component of PM10. In this study only NO_X emissions, and their role as secondary particulates is investigated. SO2 emission changes are not modeled under the assumption they are held fixed at an aggregate level under the 1990 Clean Air Act Amendments.

The mortality endpoint is the most significant in terms of estimated health effects. The default option assumes that sulfates are distinct and associates them with relatively greater potency in comparison with other constituent particles of 10 microns or less in diameter (PM10), while nitrates are treated as PM10. This characterization is the most representative of the evidence currently, but it is uncertain and other assumptions can be represented in the model. The morbidity module considers the effects of PM10 on endpoints such as symptom days and restricted activity days. NOX is included for eye irritation and phlegm days.

The Benefits Valuation Module

From an economic perspective, values are measured by how much of one asset or service individuals are willing to sacrifice in order to obtain or preserve another. The Health Valuation Submodule of TAF assigns monetary values taken from the environmental economics literature (e.g., Lee et al. 1994) to the estimated changes in health status produced by the Health Effects Module. The benefits are totaled to obtain annual health benefits for each year modeled.